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TOPICAL REPORT

RESULTS OF TASK 52 RESEARCH ON LIGHT OIL STEAMFLOODING

By D. K. Olsen, P. S. Sarathi, S. M. Mahmood, E. B. Ramzel and S. D. Roark

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Thomas B. Reid, Program Manager
U.S. Department of Energy
Bartlesville Project Office

IIT Research Institute
NATIONAL INSTITUTE FOR PETROLEUM AND ENERGY RESEARCH
P.O. Box 2128
Bartlesville, Oklahoma 74005
(918) 336-2400

TABLE OF CONTENTS

TABLES

ILLUSTRATIONS

Task 52 - DOE shall provide INTEVEP with information from research performed by NIPER on light oil steamflooding. The research will include results of studies addressing the applicability of a semianalytical predictive model (originally designed by Stanford University Petroleum Research Institute, SUPRI, for heavy oils) for use in predicting the results of light oil steamflooding. Laboratory results on selection of steam diverters for the light oil steamflood in the Shannon reservoir in Teapot Dome field, Wyoming (Naval Petroleum Reserve, NPR, No. 3) and the light oil steamflood in the Shallow Oil Zone in Elk Hills field, California, NPR No. 1, will be compared with steam diversion results from those of other heavy and light oil reservoirs.

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ABSTRACT

Research conducted as part of Task 52 evaluated a numerical semianalytical predictive steamflood model developed at Stanford University Petroleum Research Institute (SUPRI) and provided laboratory experimental support for two light oil steamfloods operated by the U.S. Department of Energy. The semianalytical numerical model is a two-dimensional (2-D) steamdrive model. As delivered, it does not permit areal modeling or modeling of cyclic steaming to increase injectivity. It is not recommended for pattern or field modeling of heavy or light oil steamfloods until modified. Recommendations are made for further advancement of the model. Laboratory 2-D steamfloods using reservoir oil and sand from the Shallow Oil Zone of Naval Petroleum Reserve (NPR) No. 1, Elk Hills field, California, show similar production characteristics and problems as encountered in the field; i.e., there is significant oil production with steam, steam reducing oil saturation below that of a waterflood, but the flood suffers from buildup of scale at the producers, migration of fines, and high CO_2 production. One-dimensional laboratory evaluation of steam diverters (foaming surfactants) was conducted for the steamfloods at both NPR No. 1 and NPR No. 3, Teapot Dome field, Wyoming. Of the tested surfactants, none was found suitable for steam diversion under conditions corresponding with those encountered in the steamflood at NPR No. 1. Chevron Chaser 1020 was found to develop a significant pressure differential in laboratory tests under the simulated NPR No. 3 reservoir conditions, indicating that this surfactant may have potential for application as a steam diverter to improve sweep efficiency to recover additional oil. Shell's LTS-18 showed similar potential in one test, but no conclusion was made because only a few tests were performed using LTS-18.

SUMMARY

This report addresses Task 52 research called for under the 7th amendment to the Annex IV agreement between the Department of Energy of the United States of America and the Ministry of Energy and Mines of the Republic of Venezuela in the area of Enhanced Oil Recovery Thermal Processes. This report summarizes NIPER's evaluation of a numerical semianalytical predictive steamflood model developed at Stanford University Petroleum Research Institute (SUPRI) and the laboratory support of two light oil steamfloods operated by the U.S. Department of Energy. The semianalytical model was found to be inadequate as delivered for modeling heavy oil field test cases and is not recommended for modeling light oil field steamfloods until modified.

Recommendations for further advancement of the model have been made to SUPRI and are also reported here. Two-dimensional (2-D) laboratory steamfloods using reservoir oil and sand from the Shallow Oil Zone (SOZ) of Naval Petroleum Reserve (NPR) No. 1, Elk Hills field, California, show similar production characteristics and problems as those encountered in the field. The 2-D laboratory steamfloods were conducted at 355° F rather than the much higher field injection temperature because of the pressure limitations of NIPER's 2-D steamflood model. Although a steamflood reduced the oil saturation to a lower level even at this lower temperature, it appeared to be an expensive way to achieve about the same oil recovery as a waterflood. The size of the waterflood recovery was nearly identical to that of the steamflood-only recovery, indicating that a waterflood was nearly as effective as a steamflood operated at the temperatures where these laboratory experiments were conducted. Implementation of steam after a waterflood does not look feasible based on these laboratory experiments.

Significant problems were also encountered when steamflooding the SOZ. The interaction of steam and hot water with the carbonaceous reservoir material in the sand caused dissolution of some of the carbonate and redeposition of minerals (scale) at the producing end of the laboratory model. The same behavior occurs in the field at producing wells at NPR No. 1. As part of the reaction of steam with carbonaceous material, a large volume of carbon dioxide is produced. Attempts to mitigate the scale formation at the producing end of the model by treatment with hydrochloric acid resulted in only a temporary improvement in permeability and producibility, but these attempts were also accompanied by liberation and migration of fines. These fines plugged laboratory filters. In the field, acidization of producing wells results in fines production causing abrasion of the seats in pumps and requiring numerous pump changes to achieve increased productivity. In the field, some scale control has been achieved by addition of scale inhibitors at the steam injector.

Attempts to find surfactants as foaming agents for effective steam diversion were unsuccessful for the high divalent ion and high temperature conditions corresponding to the steamflood at NPR No. 1. However, manufacturers have supplied additional surfactants that they believe are suitable for conditions encountered in the SOZ steamflood; but, with the suspension of the steamflood field pilot at NPR No. 1, this line of research has been discontinued. One-dimensional (1-D) laboratory evaluation of steam diverters (foaming surfactants) was also conducted for the steamflood at NPR No. 3, Teapot Dome field, Wyoming. Under simulated reservoir conditions corresponding to those of the steamflood at NPR No. 3, Chevron Chaser 1020 and Shell's LTS 18-20, commercial surfactants, have potential as steam diverters to improve sweep efficiency to recover additional oil. Only limited testing of Shell's material was conducted.

BACKGROUND

Light oil steamflooding (LOS) was being applied in two DOE-managed fields. A steamflood is being conducted in the Upper and Lower Shannon sandstone formation at NPR No. 3, Teapot Dome field, Wyoming. This multi-pattern LOS is in a highly fractured, consolidated, tight (63 mD) sandstone at a depth of 350 ft. The second LOS project is in the "Shallow Oil Zone" (SOZ) at NPR No. 1, Elk Hills field, Kern County, California. This steamflood pilot test was being conducted in a calcareous unconsolidated multisand sandstone at a depth of 2,800 ft. Both light oil steamfloods test the technology in very different environments.

The Light Oil Steamflood at NPR No. 1

The light oil steamflood pilot in the Shallow Oil Zone at Elk Hills field was performed to test the feasibility of producing some of the 100 million bbl (15.9 million m^3) of light oil (27° API) in the eastern area of the SOZ (Gangle, Weyland, Lassiter and Veith, 1990). The SOZ as a whole is still under primary production, with the major recovery mechanism being gravity drainage. The LOS targets unconsolidated Pliocene Age sands at an average depth of 3,000 ft. The target formation for the steamflood pilot, the Sub-Scalez I (SS-1), is a unit of the Scalez sand zone in the San Joaquin formation within the SOZ. SS-1 has an average thickness of 88 ft and consists of a series of fluvial/deltaic sands with an average porosity of 30%, average permeability to air of 1,000 mD, and an oil saturation of 55% (888 bbl/acre-ft) (Maher, Carter and Lantz, 1975). The sands have a high clay and carbonaceous material content. The intent of the pilot (four inverted 5-spot patterns) was to develop the background for and test the feasibility of a commercial full-scale steamflood in the eastern SOZ. The objectives of the pilot were to determine the following:

- pattern sizing—which determines the number of patterns required and hence the number of steam generators required
- completion techniques—to ensure wellbore integrity throughout the steaming phase
- profile control—since even distribution of steam vertically and areally is critical to maximizing oil recovery
- operator control—needed at Elk Hills, where thermal technology is new to field operations
- reservoir modeling—necessary for developing a usable engineering tool for screening and evaluating scaleup in the SOZ.

Achieving these technical specifications was considered the key to achieving technical and economic success.

Although operation of the pilot was suspended in the 4th quarter of 1991, the results of this pilot have been described by Gangle, Weyland, Lassiter and Veith (1990). Their paper reports that the displacement by steam was highly efficient and that steam distillation further reduced residual oil saturation. From a reservoir engineering perspective, the steamdrive process is behaving in a series of predicted events. The first expected event was the appearance of fresh water accompanied by carbon dioxide at the producing wells; this happened 3 months after the start of the steam injection. The second event, an increase in API gravity of produced crude, appeared 3 months later or 6 months into the project. Finally, the arrival of the heat front at producing wells was detected 13 months after steamflood startup. However, the pilot was not without problems. Significant oil recovery from off-pattern production was due to the geology of the SOZ. Hot wells exhibited wellbore damage and loss of productivity due to scale formation. Acid stimulations and scale-inhibitor additions to the injection stream resulted in the reduction of problems associated with scale formation.

Previous light oil steamflood field tests in sands of the same age as those of the SOZ have been conducted by Chevron in the adjacent anticline, Buena Vista Hills, NPR No. 2 (Ziegler, 1988). The Buena Vista Hills steamflood was initiated in May 1985, and suspended in May 1986. Simulation studies (Hong, 1986) field analysis (Grant and Reid, 1991) and laboratory studies of the interaction of steam and the reservoir material have been conducted. Cathles, Schoell and Simon (1987) modeled the kinetics of the reaction and detailed the interdependency of steamflooding and chemical reactiveness in the presence of carbonates. Carbon dioxide production during steamfloods has also been documented in Texaco's San Ardo field (Bleakley, 1982) and in Lacq Superior field, France (Sahuquet and Ferrier, 1982). Steamflood experiments on Lower Cretaceous McMurry formation (Alberta) by Bird et al. (1986), on Clearwater formation (Cold Lake area, Alberta) by Kirk et al. (1987), and Cretaceous Grand Rapid formation (Cold Lake area, Alberta) by Gunter and Bird (1988) showed reactions between steam and the reservoir rock. Bizon et al. (1984), Kubacki et al. (1984), and Hutcheon and Oldershaw (1985) experimentally steamed the dolomitic Devonian Grosmat formation (Alberta). Both carbonate rocks and siliclastic rocks are transformed by steam causing fines to migrate and minerals to dissolve, transform and redeposit which reduces permeability. A reference list of studies of mineral reactions has been compiled (Schenk, 1992).

The Light Oil Steamflood at NPR No. 3

The LOS at NPR No. 3, Teapot Dome field, Wyoming, has moved beyond the pilot phase and has proved to be a viable oil recovery process in the reservoir and economic environment in which it was applied. Steam stimulation was used to heat the near-well area and increase injectivity before ignition of an in situ combustion pilot (Chappelle, Emsurak and Obernyer, 1986). This steam stimulation produced significant oil, but the in situ combustion project failed due to early breakthrough. The encouraging increase in oil production due to steam stimulation led to the conversion of this in situ combustion pilot to a steamflood. The steamflood has been expanded since then to the point where four steam generators are running and a fifth is being set up.

Alternative technologies for producing oil from the Upper and Lower Shannon sandstone such as waterflooding and polymer flooding have not proven as successful as steamflooding. The Shannon steamflood is operating in a non-traditional geologic environment. Most steamfloods are conducted in thick, unconsolidated, high-permeability sands with high oil saturation. The Upper and Lower Shannon are consolidated, tight sandstones deposited as near-shore marine bar sands which have an extensive fracture network.

In the LOS in the Upper (depth, 250 ft) and Lower (depth, 400 ft) Shannon, steam of unknown quality is injected at 400 psi (445° F) and 800 psi (519° F). This is significantly above hydrostatic pressure gradient for these depths. Steam quality at the generator averages about 80%, but with approximately 90 splits per pattern in the steam distribution system, the quality (heat) to any given well could range from hot water of very low quality to steam of > 90% quality. The major oil recovery mechanisms in light oil steamflooding are distillation/steam stripping and volumetric expansion, rather than viscosity reduction which is the major recovery mechanism in steamflooding heavy oil.

RESULTS AND DISCUSSION

Evaluation of SUPRI Semianalytical Steamdrive Model

Steamflooding has generally proven to be an effective means of recovering heavy oil. However, like any other EOR process, its feasibility needs to be established before investment is made for fieldwide development. Forecasts of reservoir response to steam are critical to an engineering evaluation of a proposed steamflood project and formulation of an operation strategy.

Predictive models play an important role in estimating production performance. Many steamflood simulators are available to forecast future reservoir performance, e.g. the one by the Computer Modelling Group's general purpose thermal simulator "ISCOM". However, they are computationally expensive and require information generally not available during early screening stages of a project. The "missing" data required for a simulator can be estimated from statistical correlations or nearby similar formations. On many occasions, such as in newly developed fields and highly faulted (geologically complex) formations, the estimations are so gross as to make the investment of time and money on sophisticated thermal simulators premature.

Without a simulator, approximate production can be forecast using empirical correlations and analytical expressions. Empirical correlations can be useful for correlating data within a field and for predicting performance of similar reservoirs. However, use of these correlations for reservoirs edging off the sampled reservoirs can result in large errors. Analytical models are also available to approximate reservoir behavior, but due to mathematical complexities, they are usually simplified by applying several assumptions that limit their applicability. Semi-analytical models offer a compromise between empirical and analytical models, and if they are selected properly, they can be powerful tools. Semianalytical models are simpler to apply and provide forecasts in less time and at lower expense. These factors provide enough incentive for these models to be considered during the early stages of a proposed project, e.g. during preliminary design, planning, or screening of a reservoir.

Recently under a contract with the DOE, Stanford University Petroleum Research Institute (SUPRI) developed "SAM", a semianalytical model for the prediction of steamflood recovery performance from linear and cross sectional reservoirs (Brigham, Ramey and Castanier, 1990). This model, developed as part of Ron Gajdica's Ph.D. thesis, was designed to run on a personal computer. The model was validated by comparing predictability with ISCOM, the general purpose thermal simulator developed by the Computer Modelling Group. NIPER, under Task 52, was to extend the scope of SAM's validation by comparing its forecasts with the case histories of some documented field cases and then determine the applicability of this model to light oil steamflooding. The underlying idea was to determine if SAM could be used reliably for screening steamflood operations. This section describes the results of such comparisons with four field cases.

"SAM" Model Description

The model is based on one-dimensional linear systems and two-dimensional linear cross sectional systems (Gajdica, Brigham and Aziz, 1990). Wells are located at both ends of the reservoir. At the injection well, wet steam is injected at a constant rate and enthalpy. The production well produces at a constant flowing bottomhole pressure. It accounts for the formation dip; compressibility of the formation; and the thermal expansions of water, oil, and the formation. Water and oil are also assumed to be compressible. Heat losses to the overburden are also considered. The two-dimensional model also accounts for the gravity override of steam.

The model describes the displacement process in terms of steam and water fronts and steam, water, and oil zones. The purpose of this modeling aspect is to provide, at any time, the location of steam and water fronts and the average phase saturation in each of the three zones. The model automatically calculates the steam saturation in the steam zone.

Fractional flow theory is used to determine the location of the water front and to calculate the water zone water saturation and the unadjusted steam saturation in the steam zone. The fractional flow equation and fractional flow curve tangent construction (Leverett, 1941; Welge, 1952) are used to determine the distance to the water front. The mass-energy balance expression of Yortsos and Gavalas (1981, 1981) was used to determine the location of the steam front. The steam zone saturation is calculated from fractional flow theory and then corrected for condensation effects.

An estimate of the injection well pressure is made, and the production well pressure is determined by subtracting the calculated pressure drops through the injection well; across the steam, water, and oil zones; and through the production well. The pressure drop across the various zones is determined by iterating on the injection well pressure. After each iteration, the computed production well pressure is compared to the production well boundary condition, and the iteration is continued until convergence is achieved. In each iteration, the front location, temperatures, pressures and phase saturations are determined for each of the zones. Oil and water production rates are calculated by material balance.

In the two-dimensional model, an empirical technique is used to determine the shape of the steam front. The two-dimensional model accounts for two distinct water zones: hot water and cold water. The water zone ahead of the steam is called the cold water zone. The temperature of the cold water zone is the initial formation temperature. In both water zones, both oil and water are assumed to be mobile. The oil zone is considered to be at initial reservoir condition. The two-dimensional model uses several layers similar to the layering system in a two-dimensional simulator. To calculate the length of the steam zone in each layer, the length of the steam zone is integrated over the layer, and an average steam zone length is calculated in that layer. The temperature of the hot water zone is taken as the arithmetic average of the temperature in the steam zone and the cold water zone. The model uses the hot water zone to make volumetric calculations and to determine the production rates. The pressure drop calculations in the two-dimensional model are similar to those of the one-dimensional model.

Data Requirement for "SAM"

SAM's data requirements have been described by Gajdica, Brigham and Aziz (1990) who mentioned that the computer disks containing sample data files are available from them. A typical data input file is shown in Table 52.1 with Nomenclature.

SAM requires significantly more input data to run than similar analytical predictive models because it makes fewer assumptions than others. It accounts for the compressibility and thermal expansion of oil, water, gas, and rock as well as the dependence of fluid viscosity and density on temperature. Unlike most other predictive models, it requires extensive PVT (pressure-volume-temperature) data for fluids as well as two-phase relative permeability data. SAM requires that the relative permeability data be smooth and the saturation relative permeability end points be specified. The well data such as wellbore radius, shape factor, skin factor, injectivity and productivity indices must also be supplied. Much of the data is generally not available and must be estimated. Default values are not included. Unlike the numerical simulations, the time step size in the model is held constant, and the solution is determined at each specific point in time.

Modification Made to SAM for this Evaluation

A copy of the program was obtained from the Stanford University Petroleum Engineering Department for testing. The floppy disk supplied included the source code for the program and

TABLE 52.1

Typical Input Data Set For SAM, The Semianalytical Steamflood Model by SUPRI

GENERAL CONTROL

DELTIME	times step size	15.2
TIMMAX	maximum time	3,650.0

RESERVOIR DESCRIPTION

XANGLE	formation dip, degrees	45.0
LENG	reservoir length, ft	404.0
WID	reservoir width, ft	808.0
IGBK	number of layers in system	5.0
BLSIZK	size of block in k-direction, ft	10.0
POR	porosity, fraction	0.28
KX	permeability in x-direction, mD	500.0
AKX	average x-direction permeability, mD	500.0
AKZ	permeability in z-direction, mD	500.0

INITIAL CONDITIONS

PRES	pressure at top of reservoir, psia	70.0
PRESB	pressure at bottom of reservoir, psia	140.0
SWI	initial water saturation, fraction	0.22
SOI	initial oil saturation, fraction	0.78
TEM	temperature at top of reservoir, °F	100.0
TEMB	temperature at bottom of reservoir, °F	100.0

PVT DATA

PRORP	reference pressure for porosity, psia	14.70
PRSR	reference pressure for densities, psia	14.70
PSURF	surface pressure, psia	14.70
TEMR	reference temperature for porosity and density, °F	60.0
TSURF	surface temperature, °F	60.0
DENRW	reference water density, lb_m/cu ft	62.4
CW	water compressibility, 1/psi	0.0
CW2	water thermal expansion coefficient one, 1/°F	0.0
CW3	water thermal expansion coefficient two, 1/°F	0.0
DENRO	reference oil density, lb_m/cu ft	60.68
CO	oil compressibility, 1/psi	0.0
CO2	oil thermal expansion coefficient one, 1/°F	0.0
CO3	oil thermal expansion coefficient two, 1/°F	0.0
AVG	steam viscosity coefficient	0.00048
BVG	steam viscosity exponent	0.593

OIL AND WATER VISCOSITY DATA

IV	number of viscosity entries	2.0

TEMP (°F)	μ_w (cP)	μ_o (cP)
100.0	1.000	16.000
500.0	1.000	.160

TABLE 52.1 — Continued

OIL-WATER RELATIVE PERMEABILITY DATA

SWD(1)	irreducible water saturation, fraction	0.2
SWD(2)	maximum water saturation, fraction	0.85
KRWD(1)	water relative perm at SWD(1)	0.0
KRWD(2)	water relative perm at SWD(2)	0.0403
KROWD(1)	oil relative perm at SWD(1)	1.0
KROWD(2)	oil relative perm at SWD(2)	0.0
NOIL	Corey exponent for oil	2.0
NWAT	Corey exponent for water	3.0

GAS-LIQUID RELATIVE PERMEABILITY DATA

SLD(1)	irreducible liquid saturation, fraction	0.55
SLD(2)	maximum liquid saturation, fraction	1.0
KRGD(1)	gas relative perm at SLD(1)	0.52
KRGD(2)	gas relative perm at SLD(2)	0.0
KROGD(1)	liquid relative perm at SLD(1)	0.0
KROGD(2)	liquid relative perm at SLD(2)	1.0
NGAS	Corey exponent for gas	2.0
NLIQ	Corey exponent for gas	3.0

THERMAL DATA

CF	formation compressibility, 1/psi	0.0
CF3	formation thermal expansion coefficient, 1/°F	0.0
DENR	density for reservoir rock, lb_m/cu ft	167.0
SHR	specific heat of reservoir rock, btu/lb_m-°F	0.21
LAMOB	thermal conductivity of overburden, btu/ft/d-°F	24.0
ALFOB	thermal diffusivity of overburden, sq ft/d	0.74

INJECTION WELL

POMAX	maximum pressure at injection well, psia	1,300.0
QWAX	maximum water rate at injection well, bbl/d	700.0
QUAL	steam quality at injection sandface, fraction	0.7
TINJW	temperature of injected fluid at sandface, °F	578.0
WI	injectivity index, bbl/day/psi	99,000.0

PRODUCTION WELL

QTMAX	maximum liquid rate at producer, bbl/d	3,000.0
P5	constant fbhp at producer, psia	140.0
RW	wellbore radius of producer, ft	0.4
CC	shape factor at producer	0.0008
SS	skin factor at producer	0.0

Nomenclature for Evaluation of Predictive Model

A_p	Pattern area (acres)
A_t	Total project or pilot area (acres)
f_{sd}	Steam quality at sandface (fraction)
h_n	Net reservoir thickness (feet)
h_t	Gross reservoir thickness (feet)
k	Absolute permeability (mD)
OSR	Oil/steam ratio (bbl/bbl)
P_s	Steam pressure (psig)
$q_{s.p}$	Injection rate per pattern (bbl/pattern)
$q_{s.t}$	Total injection rate for project or pilot (bbl/d)
S_g	Initial gas saturation (fraction)
S_{oi}	Initial oil saturation (fraction)
S_{or}	Residual oil saturation to steam (fraction)
S_{wi}	Initial water saturation (fraction)
t	Life of history match (years)
T_F	Initial formation temperature (°F)
T_s	Steam saturation temperature (°F)
μ_{oi}	Oil viscosity at initial reservoir temperature (cP)
ø	Porosity (fraction)

two example data sets. Since the program had no facility for interactive data input by the user, a data file named "main dat." was created. It was felt that interactive data entry would facilitate the process; hence, the program was modified accordingly. Provision was made to save the data for future use at the end of the interactive session. The code was also modified so that the user is no longer restricted to name the input file as "main dat."

Several other modifications and clarifications were necessary. For example, it was not obvious from reading the documentation that the program expects viscosity to be in Poise rather than centi-Poise, the customary oilfield unit. The program internally converts the viscosity data from Poise to centi-Poise before proceeding with the calculation. The program initially crashed on several occasions. The logical errors causing problems had to be diagnosed and corrected by following the code itself.

Evaluation of SAM's Predictability

The model's predictive capability was evaluated by comparing the model's result with four different steamdrive projects with published case histories which included field production rates and breakthrough times. These projects were: Ingelwood field, CA (Blevins, Aseltime and Kirk, 1969), Midway-Sunset pilot, CA (Alford, 1976), Kern River-A field, CA (Bursell and Pittman, 1975), and Tatum Hefner lease, OK (French and Howard, 1967). The reservoir and petrophysical properties of these reservoirs are shown in Table 52.2. The field parameters are shown in Table 52.3. The model required very specific and detailed information about these reservoirs. Oil properties, thermal properties, relative permeabilities, and other similar data were not available. Since the model does not default input data, the missing information was estimated. Brief histories of these field projects are given in this report.

TABLE 52.2

Reservoir And Petrophysical Properties For The Steamflood Projects Studied

	Reservoir and petrophysical properties											
Field	T_f, °F	h_t, ft	h_n, ft	dip, deg	ø	k, mD	S_g	S_{oi}	S_{or}	S_{wi}	μ_{oi}, cP	Gravity, °API
Inglewood, California	100	50	43		0.39	5,900	0.00	0.64	0.20	0.36	1,200	14
Kern-River-A, California	92	74	65	3	0.35	2,300	0.00	0.41	0.06	0.59	2,200	14
Midway Sunset Pilot, California	105	330	250	10	0.27	5,200	0.00	0.59	0.15	0.41	1,500	14
Tatum-Hefner Lease, Oklahoma	75	60	50	45	0.28	500	0.00	0.78	0.15	0.22	1,600	14

TABLE 52.3

Field Parameters for Steamflood Projects Studied

	Steam parameters					Field parameters				
Field	f_{sd}	P_s, psig	T_s, °F	$q_{s \cdot p}$, B/D	$q_{s \cdot t}$, B/D	A_p, acres	A_t, acres	t, years	No. of injectors	Start of injection
Inglewood, California	0.70	350	435	1,080	1,080	2.6	2.6	1	1	Jul. 1965
Kern-River-A, California	0.70	200	388	225	255	2.7	2.7	5.5	1	Apr. 1968
Midway-Sunset, California	0.63	300	422	540	3,240	3.8	23	1.5	6	Nov. 1975
Tatum-Hefner Lease, Oklahoma	0.70	1,300	578	700	2,800	7.5	[1]30	2	4	Nov. 1964

[1] Estimated acreage between injectors and first row of producers.

Inglewood (CA) Field

This reservoir is a faulted anticline located along the Newport-Inglewood fault (Blevins, Aseltime and Kirk, 1969). The Upper Investment Zone, UB Sand was steamflooded. The pay zone has an average permeability of 5,900 mD, and the thickness varies from 40 to 60 ft. The viscosity of the 16° API crude at reservoir temperature of 100° F is 1,200 cP.

Midway-Sunset (CA) Field

The main productive zone of Midway-Sunset field is the Monarch sand found at a depth of 1,300 ft. The reservoir rock is an unconsolidated, poorly sorted 500-ft-thick sand with an average permeability of 5,200 mD. The sand contains 14° API oil with an in situ viscosity of 1,500 cP (Alford, 1976).

Kern-River A (CA) Field

The Kern River field reservoir is comprised of the Kern River series sands. The four main oil sand intervals are defined as C, G, K, and R. The "A" pilot was initiated in 1968. Steam was injected into the R member of the Kern River Series. Steam injection was limited to the lower 30 ft. The pilot area consisted of a 32% porosity sand containing 14° API (2,200 cP viscosity) oil at a depth of 600 ft. The sand permeability is 2,300 mD (Bursell and Pittman, 1975).

Tatum-Hefner (OK) Lease

The Des Moines zone VIII sand of the Hefner lease in the Tatum section of Sho-Vel-Tum field in southern Oklahoma was steamflooded in 1964. The sand is approximately 50 ft thick with an average permeability of 500 mD and 28% porosity. The sand contains a 14° API crude with a viscosity of 1,600 cP. The reservoir dips steeply (45°) to the southwest and is bounded updip by an unconformity and downdip by the oil-water contact (French and Howard, 1967).

Discussion of SAM's Performance

Steamdrive predictive models are commonly evaluated by comparing observed and predicted oil production rates and cumulative oil-steam ratio. In this study, SAM's predicted oil production rates were compared with the oil production rates for the four field cases. As shown in Figs. 52.1 through 52.4, the model poorly predicted performance of the four selected fields. SAM grossly (by orders of magnitude) overpredicted the oil production rates, underestimated the time required to achieve peak production rates, and indicated that post-breakthrough production rates (decline) were very abrupt rather than a gradual decline. It predicted an early "oil kick" at the producing well, which was not observed in the field cases even though field steamdrives usually have been cyclic steamed at least once to increase injectivity. It showed an oil production increase almost instantly after the start of steam injection. Oil production quickly reached the peak (plateau) production rate.

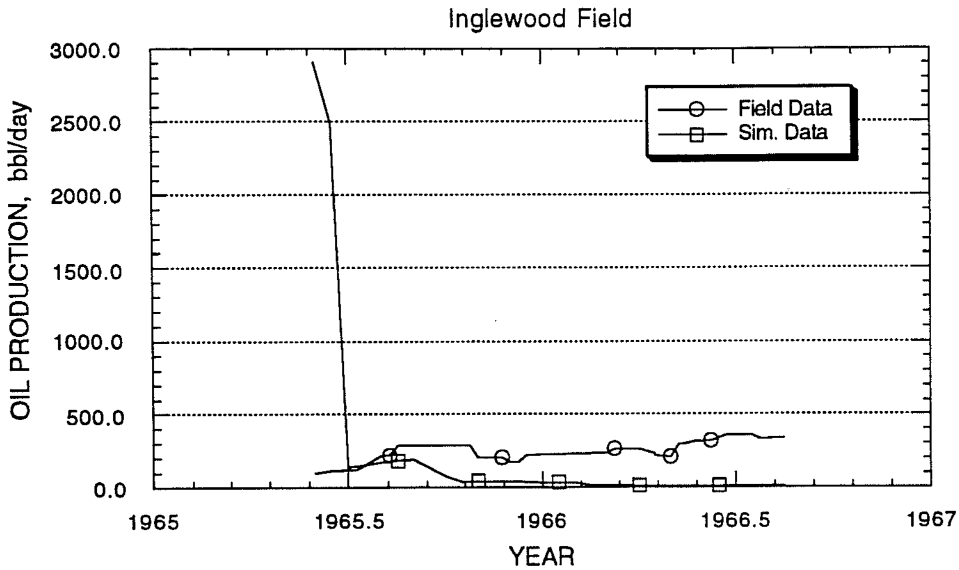

FIGURE 52.1 - Comparison of predicted and observed oil production rates — Inglewood field, California.

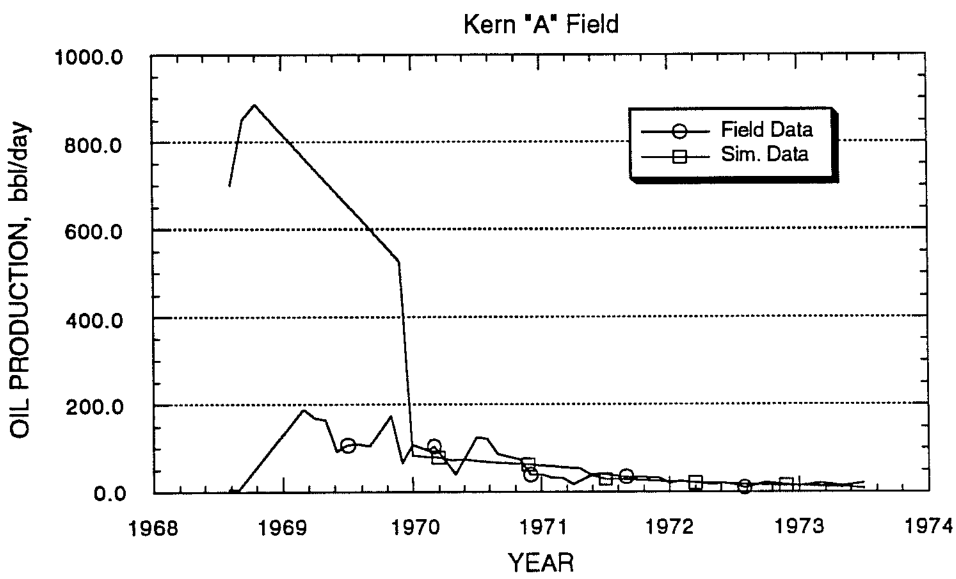

FIGURE 52.2 - Comparison of predicted and observed oil production rates — Kern River field, California.

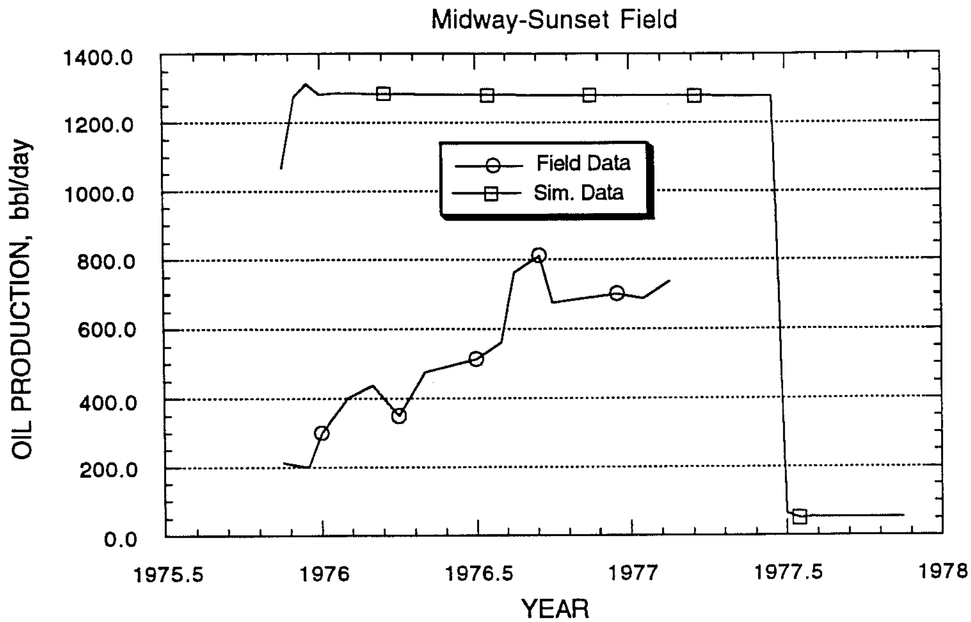

FIGURE 52.3 - Comparison of predicted and observed oil production rates — Midway-Sunset field, California.

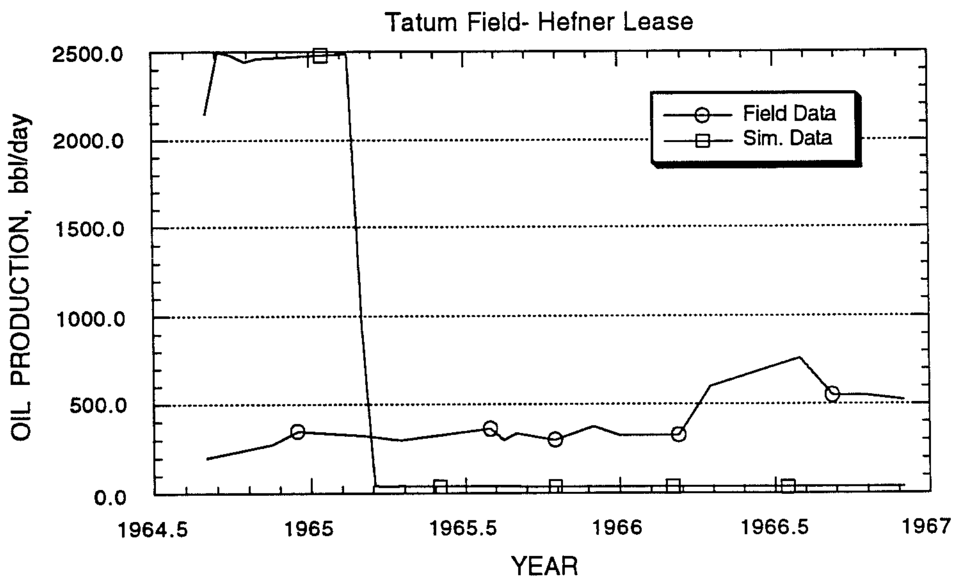

FIGURE 52.4 - Comparison of predicted and observed oil production rates — Tatum Field-Hefner lease, Oklahoma.

The production stayed at the peak rate until breakthough at which time the production of oil abruptly fell to near zero. The predicted oil production rate versus time plot exhibited a square wave behavior. The observed field data had a gradual increase in the production rate and a more gradual decline rate, as some other models would have predicted (Jensen, Sharma and Harris, 1991).

The exact reason for this wide discrepancy is not clear. One possibility may be that the selected field cases did not exactly match the model assumptions. Some obvious deviations are the preheating of field cases by cyclic steam injection which might have reduced the frontal stability of steam; or the radial flow geometry due to the well-patterns as opposed to the linear flow assumption between two wells by SAM. One field case (Tatum Field–Hefner Lease) is known to have large dip angle, whereas SAM assumes either horizontal reservoir or updip injection of steam. In all four cases, SAM predicted a piston-like behavior (i.e. more stable fronts, because it assumes that the shapes of the water and steam fronts are perpendicular to the bedding plane), whereas a more diffused displacement is suggested from the field cases. This is generally the case because the heterogeneities in the field tend to diffuse the fronts. SAM also assumes that capillary effects are negligible, an assumption which may not be supported by the field cases, even in formations of high permeability.

Conclusions and Recommendations for Semianalytical Predictive Model

The SAM model is a first major step in developing a PC-based semianalytical predictive model, but in its current condition, it grossly over estimates field production rates. The predicted production rate data had very little resemblance to the observed production data. The model results in an "oil kick" almost instantly after the start of steam injection and reaches the peak production rate within a short time. The peak production rates predicted are orders of magnitude higher than observed field production. It is suspected that this behavior may be due to the assumptions used in the development of the model and the way the zone saturations are being calculated.

Because of its poor predictive capability, this model in its present form is not recommended for use as a steamflood field screening or modeling tool. The model may be useful for predicting laboratory steamflood behavior of one and two-dimensional physical models which frequently more closely fit the assumptions used in developing SAM.

To improve the model's predictive ability and usefulness, we recommend the following:

1. Reexamine model's formulation and assumptions to identify causes for model's poor performance.
2. Reformulate the model to accommodate multiple wells and pattern configuration studies.
3. Modify the model to permit variable injection rate and pressure.
4. Include gravity override and capillary pressure features in the model.

Two-Dimensional Steam Displacement Experiments

NIPER conducted three two-dimensional (2-D) laboratory steamfloods using reservoir oil and sand from the Shallow Oil Zone (SOZ) of Naval Petroleum Reserve No. 1, Elk Hills field, California. These laboratory experiments showed similar production characteristics and problems as those encountered in the field. These experiments used friable core/sand from well 115W-10G. The larger pieces were crushed and sieved to 10-40 mesh before being packed into the NIPER 2-D steamflood model. A description and operation of the laboratory model has been previously described by Sarathi, Roark and Strycker (1990). Because of the large mesh size and because of the high clay, carbonate, and oil content of the sand, the model was packed open-faced. Previous attempts to load the model in the traditional method (through the top loading ports) did not succeed. Basic sediment and water (BS&W) tests of the crude oil from the SOZ, taken from outside the active light oil steamflooding area, yielded less than 0.1% BS & W after pressure filtration of the oil through a 2-in plug of 100 mD Berea sandstone. Oil density and API gravity of the crude oil were 0.877 g/mL and 28° API, respectively.

Simulated formation brine of the following composition per liter was prepared:

$MgCl_2 \cdot 6H_2O$ at	2.226 g
$CaCl_2$ (Anhydrous) at	0.9415 g
$NaHCO_3$ at	2.856 g
KCl at	0.1411 g
NaCl at	11.89 g

The first steamflood in the 2-D model used the friable core/sand from depth 2,828 to 2,831 ft (well 115W-10G). Dean Stark analysis showed that the core material that was packed into the model had an oil content of 7.5% by weight. This accounted for 10.9% of pore volume (PV). The model was saturated with the simulated formation brine. The pore volume and porosity of the model were determined to be 2,024 mL and 55.0%, respectively. Permeability was tested to be 581 millidarcies. The model was heated externally to 125° F, and brine in the model was displaced with oil in a recycling system (i.e. produced oil was re-injected) to achieve 61% oil saturation (original oil in place, OOIP) after flooding the model for 30 hours both horizontally and vertically. The backpressure on the 2-D model was set to 150 psi corresponding to a steam temperature of 355° F.

A steamflood of the 2-D sandpack was conducted for over 21 hours with an average cold water equivalent (CWE) steam injection rate of 4.65 mL/min. Steamflooding recovered 55.3% of the OOIP. Oil saturation was reduced from 61.0 to 27.3%, as shown in Fig. 52.5.

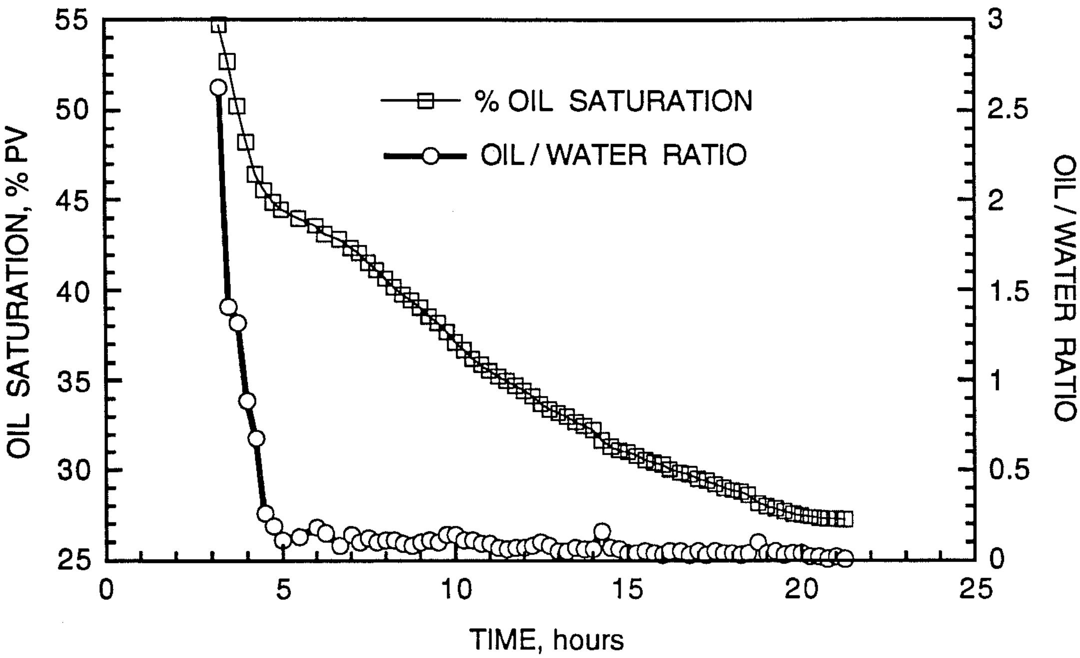

FIGURE 52.5 - Results of steamflood only in 2-D model with SOZ core (depth of 2,828 to 2,831 ft), brine and oil.

Nearly half of the recovered oil was recovered within 5 hours with the majority being produced between hours 3 and 5. When compared with NIPER's 2-D steamfloods in Quartz-sands, this is a very early production of the oil bank. Differential pressure in the 2-D model averaged 20 psi higher during this run than in 2-D steamfloods of 1.5 to 3 Darcies permeability Quartz-sands. Adjustments in the cold water pump rate to feed the steam generator were made to keep the differential pressure from becoming excessively high. At the time, the abnormally high differential pressure was thought to be caused by swelling clays or reaction of steam with some of the carbonaceous material in the sand. Throughout the steamflood, an excess of carbon dioxide was produced at the outlet.

The second and third 2-D floods on SOZ sandpacks were designed to test the effectiveness of conducting a steamflood after a waterflood. These floods also used SOZ core from well 115W-10G, but from a depth of 2,823 to 2,825 ft. Dean Stark analysis showed that the sand charged to the model contained 153 mL of oil (9.1% PV) and 140 mL of brine (8.3% PV). The model was externally heated to 150° F, 25° higher than the previous test. The permeability was 482 mD. The pore volume of this run was 1,678 mL and the porosity was 45.6%. After an extensive (>30 hour) oil injection, the oil saturation reached only 51.1% (858 mL). The waterflood recovered 38.1% of the OOIP (327 mL recovered out of 858 mL of oil). This waterflood oil recovery corresponded to a reduction in oil saturation from 51.1 to 31.6%. Most of the oil was once again recovered very early (i.e. - within 3.5 hours of the start of the run). The size of the waterflood recovery (Fig. 52.6) was similar to that of the previous run (Fig. 52.5, steamflood only from the beginning) indicating that a waterflood was nearly as effective as a steamflood under these laboratory conditions. After the waterflood, a steamflood was initiated. The average rate of steam injection during the steamflood was 4.62 mL/min (cold water equivalent). Although a steamflood reduces the oil saturation to a lower level, from these two laboratory tests, steam looks to be an expensive way to achieve about the same oil recovery as a waterflood. Implementation of steam after a waterflood does not look feasible because of the low oil saturation remaining after the waterflood.

In the second test, the steamflood was initiated 3 days after the waterflood. Three hours after the start of steam injection, the steam injection rate had to be reduced because the pressure within the model had increased, approaching the upper pressure safety limit of NIPER's 2-D model. After the first hour, high CO_2 production was noticed which continued throughout the experiment. Diagnosis of the pressure problem showed that the major pressure drop in the system was occurring at the production end of the model, where several stainless steel screens are placed to prevent sand from moving down the production line. Steam injection into the model was temporarily halted, and the pressure in the model was reduced. The production end of the model was treated (backflushed) with 10 mL of 6 Normal hydrochloric acid (HCl). Lines were reconnected, and steam was diverted back to the model. A large quantity of fines was produced, causing plugging of the downstream filter. Produced fluids were then diverted to a second set of parallel filters. This acid treatment was an attempt to remove carbonate scale buildup on the production end of the model. Production of hot oil and water proceeded normally after acidization for nearly 2 hours when the pressure again increased. Within 3 hours of the initial acidization, overpressuring of the model reached the model's safety limit. Acidization and replacement of the filters were repeatedly tried, but the problem of pressure buildup occurred within a few hours and persisted throughout the duration of the experiment.

Analysis of the plot of the second steamflood (Fig. 52.6) indicated that a small volume of oil is produced at 3rd hour after steam injection (9.5 hours cumulative time) just as the production end of the model becomes hot and steam breaks through to the producer. Steam breakthrough was assumed to occur when the temperature of the thermocouple in the production stream (connecting line from the 2-D model) was within 10° F of the steam injection temperature. This is when plugging problems occurred at the screens located at the production end of the 2-D model. A second small slug of oil is produced during hours 6-7 (12.5 - 13.5 hours cumulative time) when the model again experienced plugging at the production end of the model. The volume of this

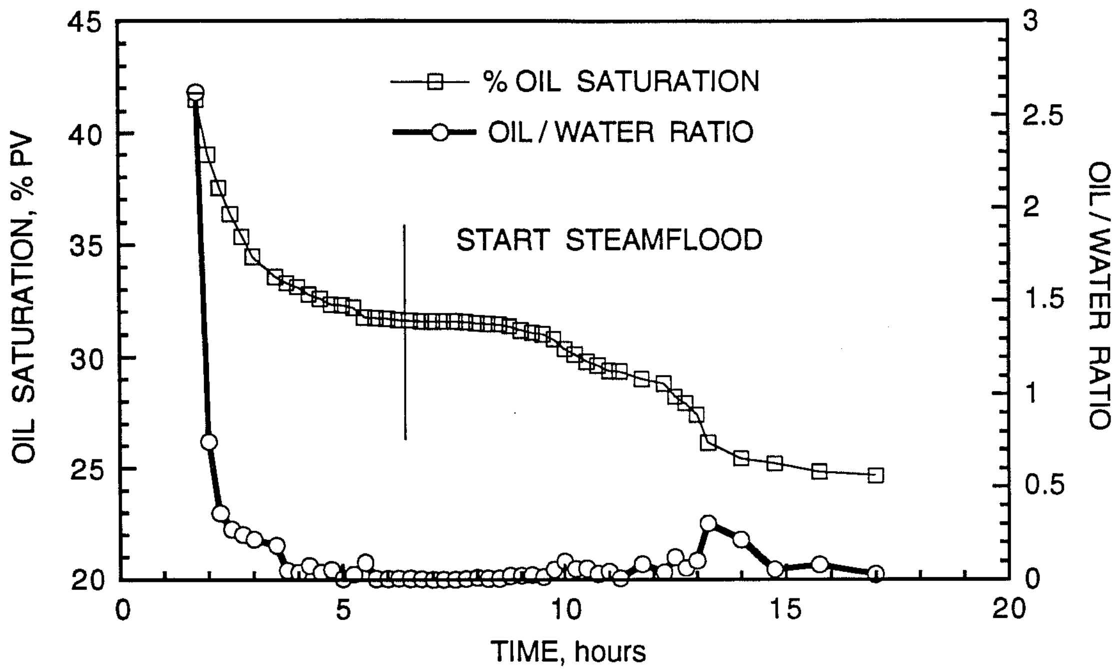

FIGURE 52.6 - Results of steamflood in 2-D model with SOZ core (depth of 2,823 to 2,825 ft), brine and oil where the model is first waterflooded to residual oil saturation and then steamflood is initiated. Downtime for acidization is not included in time.

second slug was larger as the model had been heated more thoroughly. The model experienced rapid pressure buildup (5 minutes to increase 100 psi) due to plugging of the screens when the steam broke through to the producing end. The steamflood was terminated after 11 hours of steam injection (17.5 hours cumulative time) with only an additional 7.6% PV or 13.7% of OOIP produced. The waterflood and steamflood recovered only 51.8% of OOIP. This was only 3.5% less than the first run with only a steamflood without a waterflood. The oil produced during the steamflood amounted to 22.1% of the oil left in the model after waterflood. The final oil saturation of the model at the end of steamflood was 24.6%. The average injection rate of steam for the steamflood was 4.0 mL/min (cold water equivalent).

The third experiment was also a combination waterflood followed by steamflood, as shown in Fig. 52.7. This run followed the same basic pattern as the second run with the majority of production occurring during the first 6.5 hours of the waterflood in which time the oil saturation was reduced from 51.1 to 34.3%.

The CWE injection rate of steam during the steamflood was 3.24 mL/min. Oil production during steamflood was again very small compared to the waterflooding stage. As before, pressure

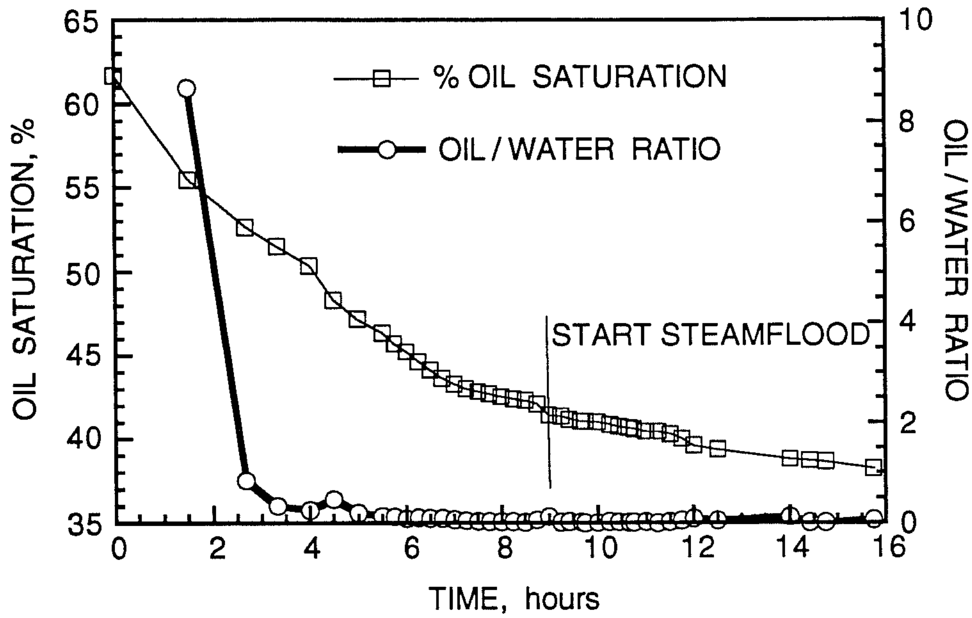

FIGURE 52.7 - Results of second steamflood in 2-D model with SOZ core (depth of 2,823 to 2,825 ft), brine and oil where the model is first waterflooded to residual oil saturation and then a steamflood is initiated.

buildup problems started after 3 to 4 hours of steam injection. A 2% KCl solution applied to the injection end helped the overpressuring problem. The steamflood was terminated after 7.5 hours (16.5 hours cumulative time) with only 44 mL of additional oil being produced or 5.13% of the OOIP. The total oil produced from both the waterflood and the steamflood was 326 mL or 38% of the OOIP. Thus, it appears that steam did very little in improving recovery in spite of all the problems of scale deposition at the producing end of the model, and the oil desaturation curve (Fig. 52.7) looks like an extended waterflood decline curve.

This production was only about 48% of the oil production in the first run and 73% of the oil production in the second run. This lower recovery can probably be accounted for by two reasons: (1) The model was not repacked when it was resaturated with oil; thus, it probably had a lower permeability (and porosity) than the initial 482 mD (and 45.6% porosity, which was already only 82.9% of the original 55% porosity in the first steamflood) due to clay swelling. Therefore, the initial oil saturation in the third run could have been lower than that of the second run and (2) The effect of frequent pressure buildup and production problems in the previous run due to clay swelling and carbonate scale deposition at the production end (both of which had probably reached their zenith) was additive to the similar problems in this run. The final oil saturation of the model was 31.7%. The cold water equivalent injection rate of steam during the steamflood was 4.23

mL/min. For the entire run including waterflood and steamflood, the rate on the average was 3.66 mL/min.

It is interesting to note the following observations: (1) Under the conditions of these laboratory tests, i.e. scale deposition and swelling, a linear model may not have been as effective as a 2-D model in diagnosing the potential field problems that may occur in steamflooding the Shallow Oil Zone. The reason is that the slug-type displacement in linear models may unjustifiably delay the first appearance of a problem; e.g. the dilution of in situ brine by the water condensed from steam appears at the production end only after preceding oil bank has been produced, thus masking its affects on productivity during the useful life of the flood. It is quite possible—as it is a common practice—that the operators might have performed linear steamflood susceptibility tests and not seen any potential problems. (2) The first steamflood required multiple pump adjustments to maintain a relatively stable flow rate and pressure across the model perhaps because the initial clay swelling and scaling were already occurring. (3) Neither of the remaining two runs had significant pressure buildup nor production problems until after introduction of steam. (4) The total amount of oil produced in the third run was almost identical to the large front end production in steamflood only test (run 1), as well as identical to the front end production waterflood segment of waterflood followed by steam test (run 2).

One-Dimensional Steam Diverter (Foam) Experiments

The three 2-D steamfloods for NPR No. 1 (as described above) had to be performed at temperatures lower than the field because of pressure limitations of the 2-D steamflood model. To address problems of premature steam breakthrough that were occurring in the field, a series of commercial surfactants were screened for possible use as steam diverters using the screening technique that has been previously described (Mahmood, Olsen and Ramzel, 1991). The tests were performed in a linear 1-D steamflood model packed with SOZ sand. Chevron Chemical Co.'s Chaser 1020, Chaser 1025 and Shell Chemical Co.'s LTS 18-20 were evaluated for potential application in the SOZ LOS. Attempts to generate a pressure drop indicative of foam or emulsion that can cause steam diversion were unsuccessful in the linear 1-D steamflood model containing reservoir sand.

Research in Support of the Light Oil Steamflood at NPR No. 3

Foam was successfully generated in clean quartz-sand over a wide variety of flow rates, surfactant concentrations, and liquid-to-vapor ratios, as shown in Fig. 52.8 (Mahmood, Olsen and Ramzel, 1991). Foam or emulsion could be generated even when the Quartz sand had been oil saturated with SOZ oil from Elk Hills and steamed to residual oil saturation. Although at residual oil saturation, higher pore volumes of surfactant were required for the same differential pressure developed using an initially water saturated sandpack (Fig. 52.9).

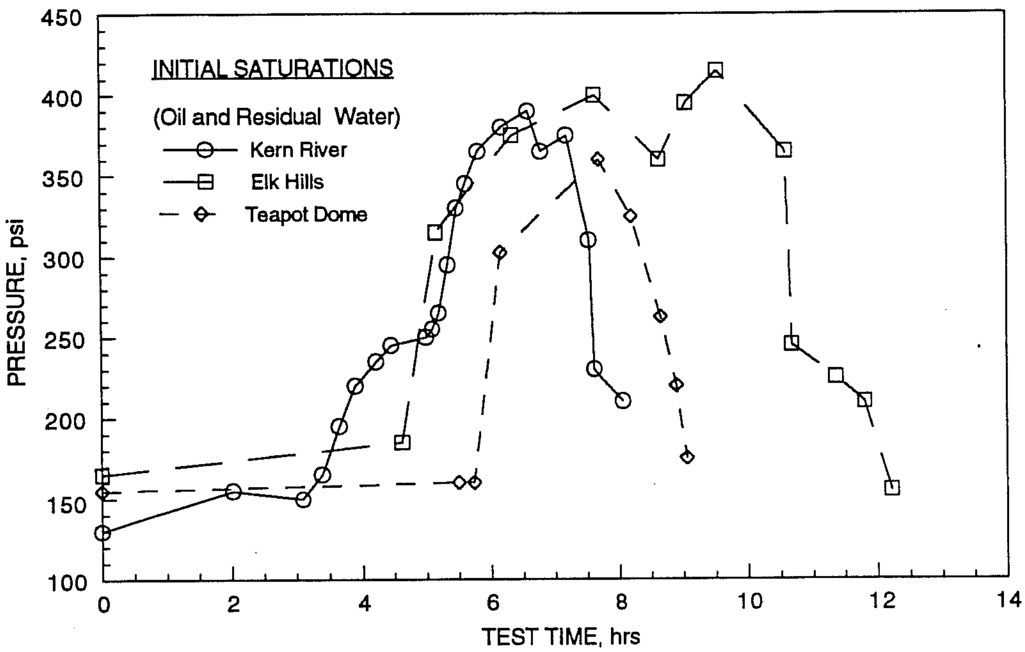

FIGURE 52.8 - **Pressure response during concurrent injection of steam, N_2, and 1% Chaser 1020 into a preheated Quartz sandpack in the presence of different oils. Backpressure on 1-D sandpack set at 150 psi.**

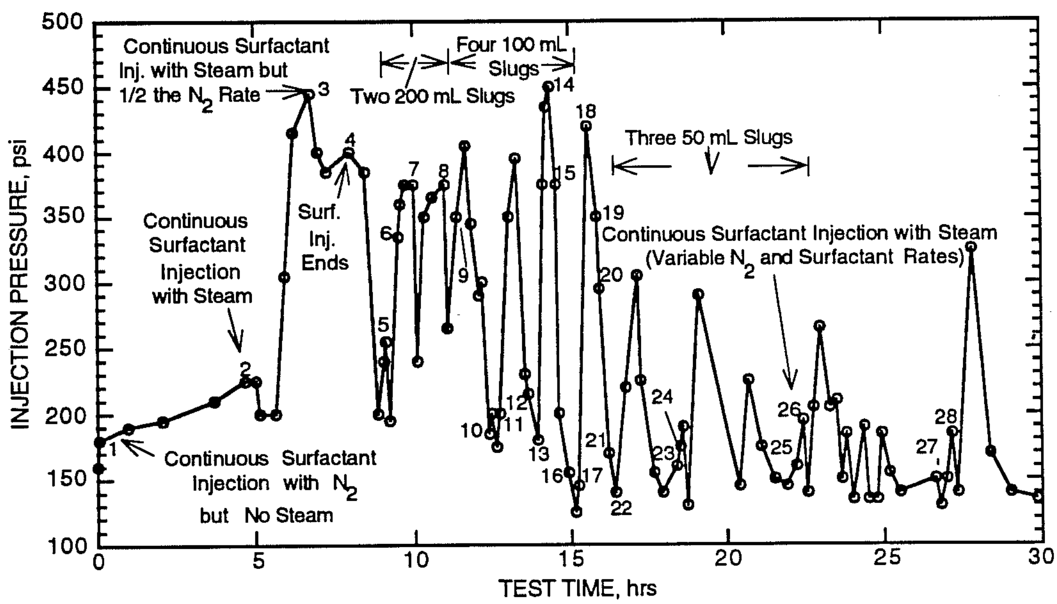

FIGURE 52.9.- **Pressure response history during another test in which operating conditions were frequently changed. Steam, N_2 and surfactant solution (1% SD-1020) were injected into a preheated sandpack initially saturated with water. The legend for the numbers on this curve is given in Table 52.4.**

TABLE 52.4

LEGEND OF SLUG SIZE AND OPERATING CONDITIONS FOR FIGURE 52.9

No. in Fig. 52.9	Description	Steam Rate mL/min (CWE)	N_2 Rate mL/min (STP)	Foamer Rate mL/min
1	No Steam	0	200	5.52
2	Continuous Foamer Inj.	9.42	200	3.33
3	Continuous Foamer Inj.	9.42	100	3.33
4	No Foamer Inj.	9.42	100	0
5	1st 200 ml Foamer Slug Inj.	9.42	100	5.52
6	No Foamer Inj.	9.42	100	0
7	2nd 200 ml Foamer Slug Inj.	9.42	200	5.52
8	1st 100 ml Foamer Slug Inj.	9.42	0	5.52
9	No Foamer Inj.	9.42	100	0
10	2nd 100 ml Foamer Slug Inj.	9.42	0	5.52
11	No Foamer Inj.	9.42	100	0
12	3rd 100 ml Foamer Slug Inj.	9.42	0	5.52
13	No Foamer Inj.	9.42	200	0
14	No Foamer Inj.	9.42	100	0
15	No Foamer Inj.	9.42	200	0
16	4th 100 ml Foamer Slug Inj.	9.42	0	5.52
17	No Foamer Inj.	9.42	200	0
18	No Foamer Inj.	9.42	100	0
19	No Foamer Inj.	9.42	150	0
20	No Foamer Inj.	9.42	200	0
21	1st 50 ml Foamer Slug Inj.	9.42	0	5.52
22	No Foamer Inj.	9.42	100	0
23	2nd 50 ml Foamer Slug Inj.	9.42	0	6.1
24	No Foamer Inj.	9.42	100	0
25	3rd 50 ml Foamer Slug Inj.	9.42	0	6.1
26	Continuous Foamer Inj.	9.42	100	5.25
27	Continuous Foamer Inj.	9.42	0	5.25

The response of 1% by weight surfactant solution (Chevron Chaser 1020) with three oils (Kern River: 13° API, Shannon oil from Teapot Dome: 32° API, and SOZ oil from Elk Hills: 27°API) are compared. In each of these 1-D tests, the Quartz sandpack was oil saturated and then steamed to residual oil saturation at which time the surfactant solution was injected. The response to the injected surfactant and nitrogen is shown in Fig. 52.8 where there is a time lag before a differential pressure across the four foot sandpack is noted. The peak foaming performance (maximum pressure drop) in each of the three tests is about the same for flow rate, surfactant concentrations, and liquid to vapor ratio. As the maximum pressure drop is attained, the system approaches the steam saturation pressure and steam condenses within the sandpack. However, the onset of foaming and the rate of pressure rise were different for each oil. The higher the degree of emulsification, the earlier the pressure kick and the slower the rate of pressure rise (Mahmood, Olsen and Ramzel, 1991). Each of the numbers on Figure 52.9 corresponds with the change in operating condition listed in Table 52.4. The time frame has been condensed in Fig. 52.9 for presentation as a single figure. An equilibrated (steady pressure) was achieved at each operating condition before a change in operating condition was initiated.

CONCLUSIONS

Three conclusions were made from the results of this study. First, the study clearly emphasizes the importance of seeking experimental support before applying a technology in the field, especially for emerging technologies such as the steam-foam process. The problems revealed in the laboratory, such as scaling and swelling were also seen concurrently in the actual field application (NPR). The fragility of steam and steam-foam processes for this reservoir, as seen in partially simulated laboratory tests, provided a hint to seek an alternative technology.

Second, it appears that the forecasting of actual field production with analytical or semi-analytical models is still not as reliable as numerical simulation. Our testing of a published semi-analytical model "SAM" on four field cases showed high disagreement between model predictions and the reported case-histories, perhaps because the fields were too heterogeneous and uncharacterizable for the simplified model.

Third, the implementation of steam after a waterflood does not look feasible under the circumstances of this study because of the low oil saturation remaining after the waterflood. The size of the waterflood recovery was nearly identical to that of the steamflood-only recovery, indicating that a waterflood was nearly as effective as a steamflood operated at this temperature. Although a steamflood reduced the oil saturation to a lower level, it appeared to be an expensive way to achieve about the same oil recovery as that of a waterflood.

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